

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report**.

Inspection Report	Post Inspection Memorandum
Inspector/Submit Date: _____	Inspector/Submit Date: _____ Peer Review/Date: _____ Director Approval/Date: _____

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator:	OPID #:
Name of Unit(s):	Unit # (s):
Records Location:	
Unit Type & Commodity:	
Inspection Type:	Inspection Date(s):
OPS Representative(s):	AFO Days:

Summary:

Findings:

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Name of Operator:		
OP ID No. ⁽¹⁾	Unit ID No. ⁽¹⁾	
H.Q. Address:	System/Unit Name & Address: ⁽¹⁾	
Co. Official:	Activity Record ID#:	
Phone No.:	Phone No.:	
Fax No.:	Fax No.:	
Emergency Phone No.:	Emergency Phone No.:	
Persons Interviewed	Titles	Phone No.
OPS Representative(s) ⁽¹⁾ Inspection Date(s) ⁽¹⁾		
Company System Maps (copies for Region Files):		
Unit Description:		
Portion of Unit Inspected ⁽¹⁾		

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections. If the inspection is in the OPS Joint O&M inspection 5 year period, procedures necessitated by new or amended regulations placed in force after the Joint Team O&M Inspection, and those known to have changed since the Joint Team Inspection, should be reviewed. Items in the procedures sections of this form identified with “*” reflect applicable and more restrictive new or amended

¹ Information not required if included on page 1.

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regulations that became effective between 2/25/00 and 2/25/05.

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CONVERSION TO SERVICE		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				

Comments:

SUBPART B - REPORTING PROCEDURES		S	U	N/A	N/C
* * .402(a) .402(c) (2)	.49	NLT June 15, 2005, operator must complete Annual Report and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.			
	.50	Accident report criteria, as detailed under 195.50. In general, 5 gallons or more, death or personal injury necessitating hospitalization , or total estimated property damage including clean-up and product lost equaling \$50,000 or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02			
	.52	Telephonically reporting accidents to NRC (800) 424-8802			
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery			
	.54(b)	Supplemental report - required within 30 days of information change/addition			
	.55	Safety-related conditions (SRC) - criteria			
	.56(a)	SRC Report is required to be filed within five (5) working days of the determination and within ten (10) working days after discovery			
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)			

Comments:

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES		S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section			

Comments:

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES		S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.					
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.			
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.			
		Welding procedures must be qualified by destructive testing.			

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SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
*	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				
	.222(a)	Welders must be qualified in accordance with Section 6 of API Standard 1104 (19th Ed., 1999) or Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.) , except that a welder qualified under an earlier edition than listed in §195.3 may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04.				
	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? (Ammon. Persulfate). Pipe must be removed for non-repairable notches.				
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				
	Nondestructive Testing Procedures					
	* .228 / .234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to Section 9 of API 1104 (19th) and as per §195.228(b) and per the requirements of §195.234 in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for NDT				
		2. By qualified personnel				
		3. By a process that will indicate any defects that may affect the integrity of the weld				
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 6 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				

Comments:

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.302(a)	Each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be pressure tested.				
	.302(b)	Except for lines converted under §195.5 , certain lines listed under this section may be operated without having been pressure tested per Subpart E.				
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				

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SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				
	.303	Procedures for the risk based alternative to pressure testing?				
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with §195.302.				
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				
	.306	Appropriate test medium				
	.308	Pipe associated with tie-ins must be pressure tested.				
	.310(a)	Test records must be retained for useful life of the facility.				
	.310(b)	Does the record required by paragraph (a) of this section include:				
	.310(b)(1)	Pressure recording charts.				
	.310(b)(2)	Test instrument calibration data.				
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				
	.310(b)(4)	Date and time of the test.				
	.310(b)(5)	Minimum test pressure.				
	.310(b)(6)	Test medium.				
	.310(b)(7)	Description of the facility tested and the test apparatus.				
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				
	.310(b)(9)	Where elevation differences in the test section exceed 100 feet , a profile of the elevation over entire length of the test section must be included				
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				

Comments:

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.402	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				
		b. Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				
		c. Appropriate parts must be kept at locations where O&M activities are conducted.				

Comments:

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Comments:

MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be followed to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph (c)(4) and minimizing the possibility of recurrence of accidents analyzed under paragraph (c)(5)?				
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by §195.406 , considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406 ?				
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under §195.402(c)(4) or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				
	* .402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per §195.59. Amdt 195-69 pub. 9/8/00, eff. 10/10/00.				
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases?				
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				

Comments:

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				
		iii. Loss of communications?				

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
	.402(d)(2)	iv. The operation of any safety device?				
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				
		Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				
		Correcting variations from normal operation of pressure and flow equipment controls?				
		Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				
		Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				

Comments:

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				
	.402(e)(5)	Controlling the release of liquid at the failure site?				
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including HVLs?				
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of HVLs by using appropriate instruments?				
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				

Comments:

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.				
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of HVL, flammability, of mixtures with air, odorless vapors, and water reactions.				

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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
*	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				
	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				
	.403(b)(2)	Make appropriate changes to the emergency response training program				
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				

Comments:

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				
		ii. Pump stations				
		iii. Scraper and sphere facilities				
		iv. Pipeline valves				
		v. Facilities to which §195.402(c)(9) applies				
		vi. Rights-of-way				
		vii. Safety devices to which §195.428 applies				
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				
	.404(a)(3)	The maximum operating pressure of each pipeline.				
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				
	.404(b)	Each operator shall maintain for at least 3 years daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under §195.402 apply.				
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the life of the pipe.				
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least 1 year.				

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MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
	.404(c)(3)	Each inspection and test required by Subpart F shall be maintained for at least 2 years, or until the next inspection or test is performed, whichever is longer.				

Comments:

MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by §195.106 .				
	.406(a)(2)	The design pressure of any other component on the pipeline.				
	.406(a)(3)	80% of the test pressure (Subpart E).				
	.406(a)(4)	80% of the factory test pressure or of the prototype test pressure for any individual component.				
	.406(a)(5)	80% of the test pressure or the highest operating pressure for a minimum of 4 hours for a pipeline that has not been tested under Subpart E .				
	.406(b)	The pipeline may not be operated at a pressure that exceeds 110% of the MOP during surges or other variations from normal operations:				
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding 110% of the MOP .				

Comments:

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				
	.408(b)	Does the communication system required by paragraph (a) include means for:				
	.408(b)(1)	Monitoring operational data as required by §195.402(c)(9) .				
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				

Comments:

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				

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LINE MARKER PROCEDURES			S	U	N/A	N/C
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				
	.410(a)(2)	Must have the correct characteristics and information				
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				

Comments:

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding 3 weeks , but at least 26 times each calendar year				
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 years .				

Comments:

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				
	.413(c)(2)	Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at each end of the pipeline segment and at intervals of not over 500 yards long , except that a pipeline segment less than 200 yards long need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
	.413(c)(3)	Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is after November 1 of that year the discovery is made, place the pipeline so that the top of the pipe is 36 inches below the seabed for normal excavation or 18 inches for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				

Comments:

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
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VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times.				
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding 7½ months , but at least twice each calendar year.				
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				

Comments:

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				

Comments:

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to 50% of the MOP .				
	.424(b)	For HVL lines joined by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain HVL , unless impractical.				
	.424(b)(2)	Have procedures under §195.402 containing precautions to protect the public.				
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of 50% of the MOP or the lowest practical level that will maintain the HVL in a liquid state. (Minimum = V.P. + 50 psig)				
	.424(c)	For HVL lines not joined by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain HVL , unless impractical.				
	.424(c)(2)	Have procedures under §195.402 containing precautions to protect the public.				
	.424(c)(3)	Isolate the line to prevent flow of the HVL .				

Comments:

SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
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STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				

Comments:

OVERPRESSURE SAFETY DEVICE PROCEDURES			S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. Non-HVL pipelines at intervals not to exceed 15 months , but at least once each calendar year.				
		2. HVL pipelines at intervals not to exceed 7½ months , but at least twice each calendar year.				
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding 5 years .				
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				

Comments:

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				
		The equipment must be:				
		a. In proper operating condition at all times.				
		b. Plainly marked so that its identity as firefighting equipment is clear.				
		c. Located so that it is easily accessible during a fire.				

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. (annually/ 15mo) includes anhydrous ammonia and any other breakout tank that is not inspected per 432 (b) & (c);				
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653 . However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3) . -Owner/operator visual, external condition inspection interval n.t.e. one month. -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, whichever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510 .				
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999 , or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				
Note: For Break-out tank unit inspection, refer to Breakout Tank Form						

Comments:

SIGN PROCEDURES			S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				

Comments:

SECURITY of FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				

Comments:

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

PUBLIC EDUCATION PROCEDURES

			S	U	N/A	N/C
.402(a)	.440	Is there a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				
		Is the program conducted in English and other languages where appropriate?				

Comments:

DAMAGE PREVENTION PROGRAM PROCEDURES

			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				
	.442(b)	Does the operator participate in a qualified One-Call program?				
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				
		ii. How to learn the location of underground pipelines before excavation activities are begun.				
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				
		ii. In the case of blasting, any inspection must include leakage surveys.				

Comments:

CPM/LEAK DETECTION PROCEDURES

			S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				

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Comments:

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)		S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.					
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :					
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under 195.424 .					
		b) Converted under 195.5 and 1) Has an external coating that substantially meets 195.559 before the pipeline is placed in service or;					
		2) Is a segment that is relocated, replaced, or substantially altered?					
	.559	Coating Materials; Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.					
	.561	a. All external pipe coatings required under 195.557 must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.					
		b. All coating damage discovered must be repaired.					
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in 195.557(a) within one (1) year ?					
		b. Each buried or submerged pipeline converted under 195.5 must have cathodic protection if the pipeline-					
		1) Has cathodic protection that substantially meets 195.571 before the pipeline is placed in service, or					
		2) Is a segment that is relocated, replaced, or substantially altered.					
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.					
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.					

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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*	SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
	e. Unprotected pipe must have cathodic protection if required by 195.573(b) .				
	.567 Test leads installation and maintenance.				
	.569 Examination of Exposed Portions of Buried Pipelines.				
	.571 Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference).				
	.573 a. (1) Pipe to soil monitoring (annually / 15months).				
	Separately protected short sections of bare ineffectively coated pipelines (every 3 years not to exceed 39 months).				
	(2) Before 12/29/2003 or not more than 2 years after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE RP0169-96 .				
	b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
	1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				
	2) Before 12/29/2003 - at least once every 5 years not to exceed 63 months .				
	Beginning 12/29/2003 - at least once every 3 years not to exceed 39 months .				
	c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - at least 6 times each year, intervals not to exceed 2½ mos.				
	d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				
	e. Any deficiencies identified in corrosion control must be corrected as required by 195.401(b) .				
	.575 Are there adequate provisions for electrical isolations?				
	.577 a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects.				
	b. Design & install CP systems to minimize effects on adjacent metallic structures.				
	.579 a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				
	b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				
	Coupons or other monitoring equipment must be examined at least 2 times each year, not to exceed 7 ½ months .				
	c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				
	.581 Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				
	.583 Atmospheric corrosion monitoring -				
	ONSHORE - At least once every 3 years but at intervals not exceeding 39 months .				
	OFFSHORE - At least once each year, but at intervals not exceeding 15 months .				
	.585 a. Are procedures in place and are they followed to either reduce the MOP , or repair/replace pipe if general corrosion has reduced the wall thickness?				

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* SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)			S	U	N/A	N/C
		b. Are procedures in place and are they followed to either reduce the MOP , or repair/replace if localized corrosion has reduced the wall thickness?				
	.587	Are applicable methods used in determining the strength of corroded pipe (ASME B-31G, RSTRENG) ?				
	.589	Corrosion Control Records Retention (Some are required for 5 yrs ; Some are for the service life).				

Comments:

Alert Notices:

What process does the Operator have to address Alert Notices?

Comments:

Recent Pipeline Safety Advisory Bulletin

ADB-04-03 in August 18, 2004 Federal Register, pp. 51348-51349 (Ref. **fr18au04N Pipeline Safety: Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities**)

Reference <http://www.gpoaccess.gov/fr/advanced.html>

Best Practice: Stress Corrosion Cracking

Pipeline Safety Advisory Bulletin ADB-03-05 in October 8, 2003 Federal Register, pp. 58166-58168 (Ref. **fr08oc03N Pipeline Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Liquid Pipelines**).

Reference <http://www.gpoaccess.gov/fr/advanced.html>

Is the operator aware of the SCC bulletin, and is the operator reviewing their system for the potential of SCC?

Y/N _____

PART 195 - FIELD REVIEW			S	U	N/A	N/C
.262	Pumping Stations					
.262	Station Safety Devices					
.308	Pre-pressure Testing Pipe - Marking and Inventory					
.403	Supervisor Knowledge of Emergency Response Procedures					
.410	Right-of-Way Markers					
.412	River Crossings					

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.420	Valve Maintenance				
.420	Valve Protection from Unauthorized Operation and Vandalism				
.426	Scraper and Sphere Facilities and Launchers				
.428	Pressure Limiting Devices				
.428	Relief Valves - Location - Pressure Settings - Maintenance				
.428	Pressure Controllers				
.430	Fire Fighting Equipment				
.432	Breakout Tanks				
.434	Signs - Pumping Stations - Breakout Tanks				
.436	Security - Pumping Stations - Breakout Tanks				
.438	No Smoking Signs				
.501-.509	Operator Qualification Questions, Observations - See Attachment 3				
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)				
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds				
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbonded coatings, supports, deck penetrations, etc.)				

PART 195 - RECORDS REVIEW		S	U	N/A	N/C
CONVERSION TO SERVICE					
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.				
.5(c)	Pipeline Records (Life of System)				
	Pipeline Investigations				
	Pipeline Testing				
	Pipeline Repairs				
	Pipeline Replacements				
	Pipeline Alterations				
REPORTING					
.49	Annual Report (DOT form RSPA F7000-1.1 Beginning no later than June 15, 2005)				
.52	Telephonic Reports to NRC (800-424-8802)				
.54(a)	Written Accident Reports (DOT Form 7000-1)				
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)				
.56	Safety Related Conditions				
.57	Offshore Pipeline Condition Reports				
.59	Abandoned Underwater Facility Reports				
CONSTRUCTION					
.204	Construction Inspector Training/Qualification				

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.214(b)	Test Results to Qualify Welding Procedures				
.222	Welder Qualification				
.234(b)	Nondestructive Technician Qualification				
.589	Cathodic Protection				
.266	Construction Records				
.266(a)	Total Number of Girth Welds				
	Number of Welds Inspected by NDT				
	Number of Welds Rejected				
	Disposition of each Weld Rejected				
.266(b)	Amount, Location, Cover of each Size of Pipe Installed				
.266(c)	Location of each Crossing with another Pipeline				
.266(d)	Location of each buried Utility Crossing				
.266(e)	Location of Overhead Crossings				
.266(f)	Location of each Valve and Test Station				
PRESSURE TESTING					
.310	Pipeline Test Record				
.305(b)	Manufacturer Testing of Components				
.308	Records of Pre-tested Pipe				
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (1 per yr/15 months)				
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions				
.402(c)(10)	Abandonment of Facilities				
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials				
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures				
.402(d)(1)	Response to Abnormal Pipeline Operations				
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures				
.402(e)(1)	Notices which require immediate response				
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency				
.402(e)(9)	Post Accident Reviews				
.403(a)	Emergency Response Personnel Training Program				
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (1 per yr/15 months)				
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures				
.404(a)(1)	Maps or Records of Pipeline System				
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines				
.404(a)(3)	MOP of each Pipeline				
.404(a)(4)	Pipeline Specifications				

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)				
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)				
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)				
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)				
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)				
.406(a)	Establishing the MOP				
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.				
.412(a)	Inspection of the ROW				
.412(b)	Inspection of Underwater Crossings of Navigable Waterways				
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk				
.420(b)	Inspection of Mainline Valves				
.428(a)	Insp. of Overpress. Safety Devices (1 per yr/15 months non-HVL; 2 per yr/7½ months HVL)				
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE 5 yrs).				
.428(d)	Inspection of Overfill Systems (1 per yr/15 months non-HVL; 2 per yr/7½ months HVL)				
.430	Inspection of Fire Fighting Equipment				
.432	Inspection of Breakout Tanks (1 per yr/15 months or per API 510 or 653).				
.440	Public Education				
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators				
.442(c)(2)	Notification of Public/Excavators				
.442(c)(3)	Notifications of planned excavations. (One -Call Records)				
CORROSION CONTROL					
.589(c)/.567	Test Lead Maintenance, frequent enough intervals				
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)				
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (1 per yr/15 months)				
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)				
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (1 per 3 cal yr/39 months)				
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers				
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks				
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).				
.589(c)/.575	Electrical isolation inspection and testing				
.589(c)/.577	Testing for Interference Currents				
.589(c)/.579(a)	Corrosive effect investigation				
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (2 per yr/7½ months)				
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion				

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.589(c)/.583(a)	Atmos. Corr. Monitoring (1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)				
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG				
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP				
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)				

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]			
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]			
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]			

Comments (If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the “sequence number.” It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1

SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

The topics on this worksheet regard general SCADA functionality. A more thorough SCADA evaluation may be warranted based on the results of this worksheet or prompts by other events.

1. Pipeline Safety Advisory Bulletins (reference <http://www.gpoaccess.gov/fr/advanced.html>)

Review the following with the operator:

- Advisory Bulletin ADB-99-03 in July 16, 1999 Federal Register p.38501 (Ref. **fr16jy99N Potential Service Interruptions in Supervisory Control and Data Acquisition Systems**) - discuss SCADA system performance.
- Advisory Bulletin ADB-03-09 in December 23, 2003 Federal Register, pp. 74289-74290 (Ref. **fr23de03N Pipeline Safety: Potential Service Disruptions in Supervisory Control and Data Acquisition Systems**) - discuss consideration of possible SCADA system disruptions caused by system maintenance or upgrade.

Comments:

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. 195.402(d)(1)(iii) - Loss of communications.

- Off-site Back-up Center
- Data transfer to redundant or off-site processors
- Battery and/or Emergency Generator
- Redundant data communications paths, automatic restoration or manual?
- Data Reduction & Archiving
- Indication of stale, forced or manually overridden data, or system lock-up
- Operating practices during data communications outages

Comments:

3. §195.404 - Pump station discharge pressure records.

- Discharge Pressure records in SCADA or at field locations?
- Data Reduction & Archiving
- Data acquisition frequency

Comments:

4. §195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of the following pipeline facilities:

- (i) Breakout tanks;
- (ii) Pump stations;
- (iii) Scraper and sphere facilities;
- (iv) Pipeline valves;
- (v) Facilities to which §195.402(c) (9) applies;

Attachment 1

SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

(vii) Safety devices to which §195.428 applies.

(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations.
- Ensure pipeline safety parameters are current (i.e., MOP, alarm set points, etc.)
- Review any emergency or abnormal operating condition or schedule deviation records generated by the SCADA system (alarm logs, trending data, etc.). Compare abnormal operating conditions noted in the SCADA data with the operator's report and reporting procedures as related to those abnormal operating conditions.
- Data Reduction & Archiving
- Data acquisition frequency

Comments:

5. §195.408 - Communications.

(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system

(b)(1) Monitoring operational data as required by §195.402(c)(9)

- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-short Reports
- Maintaining pressures within limits described in **§195.406 Maximum Operating Pressure**

Comments:

6. §195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance

- Over-Short Reports
- Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments:

§195.420 & .428 - Testing of applicable SCADA controlled valves, safety devices, and overfill systems functionality.

- Frequency of testing
- Inclusion of SCADA component in the tests

Comments:

Attachment 2

Internal Corrosion Worksheet - Liquid Pipelines

If an item is found to be unsatisfactory, an explanation must be included in this report.

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: _____ N: _____
2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: _____ N: _____
3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: _____ N: _____
4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: _____ N: _____
5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: _____ N: _____
6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y: _____ N: _____
7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)?
Y: _____ N: _____
8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion?
Y: _____ N: _____
9. Does the operator track internal corrosion and take corrective action to prevent recurrence? Y: _____ N: _____
10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
____ Gas and Fluid analysis
____ Rates of pipeline corrosion as determined by coupons
____ Solids removed from the system
____ Analysis of inhibitor samples from the pipeline
____ Magnetic and electronic device (pigs)
____ Other
11. Is the inhibitor compatible with the product being transported? Y: _____ N: _____ N/A: _____

Comments:

Attachment 3

Operator Qualification Worksheet

For any item below checked N, an explanation must be included in this report.

The following questions are to be used by the inspector to provide information in determining a need for a more intensive OQ field inspection.

1. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual's performance of a covered task may have contributed to an incident? Y _____ N _____
2. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual is identified who may no longer be qualified to perform a covered task? Y _____ N _____
3. Do the individuals performing covered tasks know how to recognize and react to abnormal operating conditions (AOCs) that may be encountered while performing tasks? Y _____ N _____
4. Are the employee and/or contractor individuals observed performing covered tasks qualified per OQ program requirements? (Documentation may be a hardcopies or database records available at the job site or local office.) Y _____ N _____
5. Are the individuals who are observed performing covered tasks adhering to operator's procedures? Y _____ N _____

Comments: